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April 3, 2017

VIA, ELECTRONIC FILING
The Honorable Jocelyn Boyd
Chief Clerk and Administrator
The Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

Re: • Docket Number 2017-2-E

Dear Ms. Boyd:

Enclosed for filing please find the Surrebuttal Testimony of Dr. Ben Johnson on behalf of Intervenor, South Carolina Solar Business Alliance, LLC, Cover Sheet and Certificate of Service.

All parties of record have been served. Please notify the undersigned if you there is anything else you may need.

Respectfully Submitted,

/S/________________
Richard L. Whitt

RLW/cas

SURREBUTTAL TESTIMONY OF

Dr. Ben Johnson

ON BEHALF OF THE

SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

Before the

PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2017-2-E

Introduction

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. Ben Johnson, 5600 Pimlico Drive, Tallahassee, Florida.

Q. HAVE YOU PREVIOUSLY SUBMITTED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I am responding to the rebuttal testimony of Joseph M. Lynch, on behalf of South Carolina Electric & Gas Company ("SCE&G" or the "Company") concerning the proposed rates to be paid to Qualified Facilities ("QF")

Q. WHAT IS THE SCOPE OF THIS TESTIMONY?

A. My surrebuttal is focused on two key issues which I believe are of particularly great importance. While I am not responding to some of the statements in Mr. Lynch's testimony – especially in the section where Mr. Lynch rebuts Dr. Vitolo – that should not be construed as agreement with those statements. My disagreement can be discerned by comparing those statements with my direct testimony.

I also have not responded to the direct testimony of Brian Horii on behalf of the Office of Regulatory Staff ("ORS"). I view that testimony as being much more narrowly focused than my own testimony (or that of Mr. Lynch, for that matter). His testimony seems to largely focus on what changes, if any, the Company made to the methodology and inputs it used in Docket No. 2016-2-E. In contrast, I considered the inputs and other assumptions used by the Company from a much broader perspective. For example, my direct testimony raised questions about how well the Company's inputs and assumptions comport with the theoretical underpinnings of the Differential Revenue Requirement ("DRR") method, how the results of the Company's calculations compare to the analogous calculations and rates approved by this Commission for Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"), and how those results stack up against various broader criteria, like the underlying goals of the 1978 Public Utility Regulatory Policies Act ("PURPA").

I realize time constraints make it difficult for the Commission to fully evaluate these broader concerns in this proceeding. I also realize that, from an administrative perspective, this might not be the ideal forum for fully exploring and resolving these broader concerns. Nevertheless, I would urge the Commission to not simply dismiss these concerns, or assume they have already been dealt with adequately. Whatever the Commission decides to do with the current rate filing, I would urge it to evaluate these issues in greater depth at another time. This could be accomplished in a separate proceeding focused on the appropriate application of the PURPA to SCE&G. I believe this would serve the long term best interests of the Company's retail ratepayers, and enable the Commission to better understand and help shape the future of the solar industry in South Carolina.

Bearing this in mind, I will be discussing three key points which are pivotal to understanding why the Company's proposed QF rates are so low, and why SCE&G's approach to QF rate development is not optimal from a public interest perspective.

Solar Characteristics

Q. WHAT IS THE FIRST ISSUE?

A. I will respond to the impression Mr. Lynch gives that power provided by solar Qualified Facilities ("QFs") is inferior to that provided by the Company's own generators. For instance, he testifies that "SCE&G cannot sell firm, dependable capacity that is backed by an intermittent resource such as a solar QF."[1] He also discusses some data concerning a particular solar facility that may explain his negative attitude:

> The data therefore demonstrates that this solar facility provides little, if any, firm dependable capacity to SCE&G's system which the Company can reliably call upon to serve its customers.[2]

This conclusion is incorrect, as I will explain below. The negative inference Mr. Lynch has drawn concerning the intermittent characteristics of solar energy seems to have negatively impacted his entire approach, leading him to misjudge the benefits of solar generation, and propose QF rates at the extreme low end of the range of potential rate levels. For example, in explaining his decision to not give QF's any credit whatsoever for helping to avoid transmission and distribution costs, he states:

> SCE&G's distribution engineers must plan the distribution line assuming the solar output is zero because solar is an intermittent resource. While this may change in the future as SCE&G has more

1 Rebuttal Testimony of Joe Lynch, Page 26.

2 Rebuttal Testimony of Joe Lynch, Page 12.

> experience with solar QFs on the system, SCE&G has set the avoided cost relative to transmission and distribution at zero at this time.[3]

This negative attitude toward solar QFs is not limited to avoidable transmission and distribution costs, nor is it well-founded. As distributed generation is introduced in diverse locations, there are opportunities to avoid the need for capital expenditures on improving and expanding substations and other portions of the distribution and transmission system. Mr. Lynch's rebuttal reflects a deeply flawed view of solar power, and a failure to fairly judge the advantages and disadvantages of solar energy in comparison with more traditional energy sources like nuclear, coal, residual oil, and natural gas.

Q. MR. LYNCH DESCRIBED SOLAR GENERATION AS "INTERMITTENT." IS THIS A SERIOUS PROBLEM?

A. No. Solar production is "intermittent" because it only occurs when the sun is shining. Every night, a solar QF stops sending energy to the grid. However, this "intermittent" characteristic isn't a serious problem, nor does it pose any major risks. Obviously, there is no risk the sun won't come over the horizon tomorrow, so the fact that energy production abruptly stops overnight isn't a cause for alarm, nor does this have to create problems for managing the system. On balance, the largely predictable, daytime-only

3 Rebuttal Testimony of Joe Lynch, Pages 14-15.

characteristics of solar production are actually an advantage, because production tends to correlate reasonably well (but not perfectly) with the times when energy usage is highest.

Of course, solar output is not entirely free of weather-related uncertainties, since it is affected by cloud cover, which is less predictable than the rising sun. While this is a disadvantage, it is not as serious a concern as it might appear. As I discuss below, all energy sources involve some degree of uncertainty – just in different areas. It is fair to say that cloud cover introduces an element of uncertainty, but this is not a serious enough problem to make solar energy less attractive than traditional alternatives. All forms of electrical energy production have their own unique set of characteristics, which translate into some inherent advantages and disadvantages. Solar energy is no exception.

There are also mitigating factors which limit any reason to be concerned about cloud cover. First, when solar energy is provided by numerous, widely dispersed QFs, the benefits of diversification come into play, resulting in greater stability in system-wide solar output than will be measured at any given location. Second, with improved real time metering and data collection and some straightforward computer modeling, the Company can begin to predict solar energy production on its system on a reasonably precise, hour-by-hour basis, further obviating any concern about cloud cover. This will allow the Company to treat solar energy as a routine, reliable and predicable portion of its daily dispatch process—further alleviating the concerns expressed by Mr. Lynch. Third, in South Carolina the need for electricity tends to be greatest on hot, sunny days, when air conditioning loads are high. In contrast, electrical usage tends to be somewhat lower on cloudy or rainy days, when the need for air conditioning is not as severe. So, even in the absence of better metering and statistical analysis, we can be confident that variations in solar output are – and will continue to be – favorably correlated with variations in customer load.

Q. MR LYNCH EMPHASIZED WHAT HE PERCEIVES TO BE DISAVANTAGES OF SOLAR ENERGY. ARE THERE ALSO DISADVANTAGES TO OTHER ENERGY SOURCES?

A. No energy source is entirely free of disadvantages. Combustion turbines ("CTs") have the advantage of being relatively inexpensive to build, but they burn a lot of oil or gas, which increases the cost per kWh, and makes it difficult to predict what that cost will be.

Combined cycle units have the disadvantage of costing more to build than a CT, and they share some of the same fuel price risks as CTs. On the plus side, they have excellent heat rates; making them more cost-effective than a CT when serving loads of long duration. This advantage is particularly significant in our current environment of low oil and gas prices. The disadvantage – and it is a very serious one – is that the price of gas and oil is subject to severe fuel price volatility and geopolitical uncertainty, which makes it impossible to accurately predict the level of oil and gas prices that will prevail over the entire 30+ year economic life of a generating plant.

While natural gas prices are currently trading at very attractive levels, they have historically been very volatile. Furthermore, oil and gas are sometimes produced in tandem, so both prices tend to be subject to significant international geopolitical risks. Most forecasts have projected (and to a lesser degree continue to project) oil and gas prices that escalate much more rapidly than the overall inflation rate, over the long term. Since fuel prices are forecast to increase, and there is considerable risk associated with those forecasts, a utility that entirely relies on gas-fired generation will subject its customers to a lot of risk that can be avoided when other fuel sources are also used.

Another disadvantage is that these units are subject to mechanical failures and the need for maintenance which keeps them from providing energy on a 100% reliable basis – a problem that is shared by all fossil fueled generators to one degree or another. Data provided to ORS by SCE&G shows widely varying projected monthly availability factors for its generating plants ranging below 50% during 2017, and even lower for some plants during some months in 2018. [4]

Coal is an even more physically and technically challenging than gas, which helps explain why coal plants tend to be more costly to build and operate. Problems with physical wear and tear and other issues force all fossil fueled generating units off line from time to time. This disadvantage requires the utility to maintain other capacity

4 SCE&G response to ORS Audit Request 2-4.

standing ready to serve as a backup, to ensure the grid remains energized when a unit shuts down for either scheduled or unscheduled maintenance.

Although this disadvantage is important for coal, coal prices have sometimes been lower (per $MMBTU) and/or less volatile than oil and gas prices. At least in the United States, coal has historically been a vitally important fuel source because ample domestic supplies existed which could easily be obtained using existing mining technology. Mining costs have been reasonable and inherently stable, which has been one of the greatest advantages of coal. Because competition in both the mining and transporting of coal have been vigorous, some utilities have relied very heavily on coal, while largely steering clear of nuclear, oil and gas, which were viewed as too risky.

Fuel price stability has historically proven to be the greatest advantage of nuclear plants. The benefit of lower fuel-related risks helps explain why utilities have continued to select this technology, despite its risks and other disadvantages, including an extraordinarily high level of federal regulation, and the potential for becoming a political lightning rod. These disadvantages, in turn, help to explain the other major disadvantage: it is hard to predict how long it will take, or how much it will cost, to build a nuclear plant. Since fuel costs are a relatively small part of the overall cost of nuclear production, uncertainties concerning when a plant will be completed, and what the cost per kWh will be, pose two very serious challenges, which have discouraged some utilities from pursuing this option more vigorously. In practice, despite the problems, once plants are completed, the lack of exposure to volatile, rising fuel costs has generally made nuclear plants a cost-effective, low-risk option over their full 60+ year economic life cycle.

Hydro, solar and wind power offer even more cost stability and lower fuel-related risks than nuclear plants. Nuclear plants use uranium, which is subject to cost escalation, but it can be purchased under long term contracts with stable, predictable prices. Nuclear production also involves significant uncertainties and risks related to the disposal of uranium after it has been used to produce electricity. In contrast, hydro, wind, and solar enjoy the advantage of not consuming <u>any</u> fuel, which leaves them entirely free of any fuel-related risks.

Of course, no energy source is entirely risk free. For instance, hydro is dependent upon rainfall, so it is subject to the inherent risks and uncertainties associated with annual and monthly variations in snow, rain and river conditions. Similarly, windmills only generate electricity when the wind is blowing – which is a deal-breaker in some areas, but not as serious a problem in areas with strong, steady winds. And, as I noted, solar is subject to uncertainty concerning cloud cover.

Q. DOES SOLAR ENERGY OFFER SYNERGISTIC BENEFITS WHEN USED IN CONNECTION WITH OTHER ENERGY SOURCES?

A. Yes. Since all of the options have different advantages and disadvantages, it is a mistake to think in terms of trying to choose the one "perfect" energy source. Instead, a portfolio strategy makes more sense: alternative energy sources should be viewed partly from the perspective of how well they fit into an overall generation mix.

Contrary to the impression given in Mr. Lynch's rebuttal, solar energy is particularly attractive not when it is used on a stand-alone basis, but when it is added to a broader generation mix that includes fossil fuels production, because solar can be purchased from QFs at long-term fixed prices which are independent of fluctuations in coal, oil and gas prices. When solar is blended with electricity from fossil fuels, customers gain the benefit of a stabilizing element being introduced into the overall cost structure, which reduces the volatility of retail electric prices and utility bills. This favorable impact is similar to the dampening effect which is achieved when short term bonds or bank certificates of deposit are added to a portfolio that mostly includes common stocks.

The reduction in volatility attributable to long term solar power helps all types of customers – including commercial and industrial customers – who can more accurately predict their utility costs. In turn, this helps strengthen the state's economy and provides a more stable and attractive business environment.

Solar is also attractive when it is used in conjunction with nuclear power, which is normally produced at a steady rate, 24 hours a day, 7 days a week. When a layer of solar is added on top of an around-the-clock pattern of nuclear production, the combination of the two better fits the normal pattern of daily variations in energy usage – most customers use more electricity during the day, and less at night. Of course, the combination of nuclear and solar output alone will not achieve a perfect match to customer usage, so other sources are obviously also needed in the portfolio to serve as spinning reserves, and help achieve a precise matching of supply and demand throughout the day.

In sum, every energy option has advantages and disadvantages, along with associated risks. Despite the impression which is given in Mr. Lynch's rebuttal testimony, solar is actually one of the most attractive, least risky options available. Customers will benefit as more solar is added to SCE&G's long-term energy portfolio, and the Company learns how to adapt its operations to more effectively take advantage of this energy source.

Q. MR. LYNCH IMPLIES THAT SOLAR QFS DO NOT PROVIDE DEPENDABLE CAPACITY. DO YOU AGREE?

A. No. Mr. Lynch gives the impression that solar output is highly unpredictable and unreliable.

> I do not believe that it is reasonable or meaningful to compare the intermittent capacity of a solar QF, which only provides energy as

> weather permits, with the firm capacity of a more dependable generating unit such as a combustion turbine.
>
> By way of an example, the maximum hourly output of a large solar generator on SCE&G's system in 2016 was 2,042.4 kW. However, there was only one hour in the year that the solar generator generated 2,042.4 kWs, only 6 hours where its output was above 2,000 kWs, and only 35 hours when its output was within 100 kWs of its maximum. Accordingly, this facility only generated energy near its maximum output for 0.4% of the hours for the year. Moreover, its output was above 50% of its maximum for only 18% of the hours and for 51% of the hours its output was zero.
>
> The data therefore demonstrates that this solar facility provides little, if any, firm dependable capacity to SCE&G's system which the Company can reliably call upon to serve its customers.

However, these statistics are misleading, because they give the impression solar power is unpredictable, when in fact it is highly predictable. For instance, the fact that output was zero during 51% of the hours makes perfect sense, when you remember the QF doesn't send energy to the grid during the night. Similarly, solar output rises throughout the morning, it peaks around mid-day, then gradually declines until it sharply drops off as the sun sets. Since all of this variation in output is well understood, there is no reason for the Company to view solar capacity as unreliable or undependable.

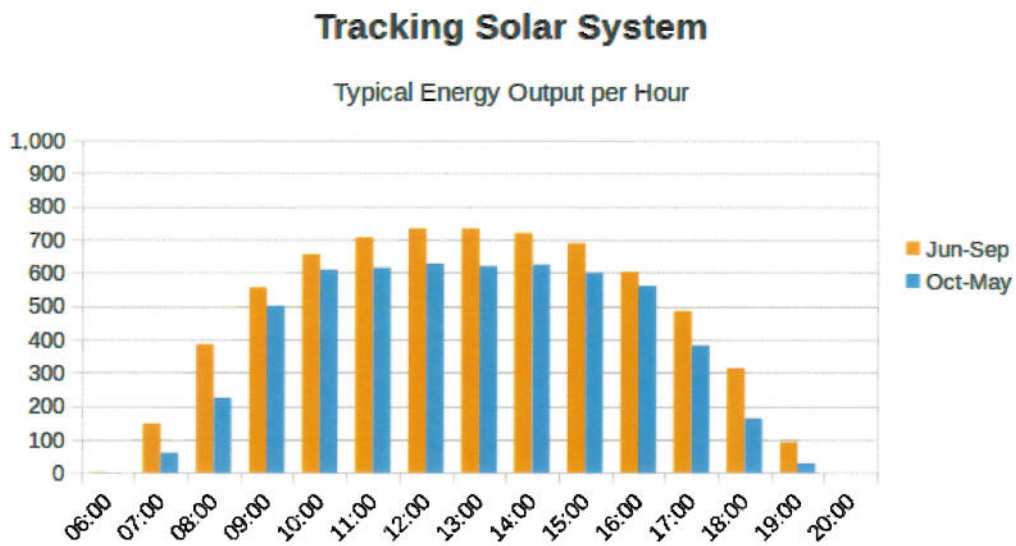
More subtly, and perhaps more importantly, the numbers provided in Mr. Lynch's rebuttal are based upon nameplate capacity, which is largely irrelevant to the question to the question of how much capacity will be provided by a solar QF during each hour of the day. A QF is only paid for the <u>actual</u> energy it sends to the grid during any given hour – it is not paid anything based upon its nominal nameplate capacity. Similarly, it is only paid for capacity to the extent it actually delivers energy during the limited "On Peak" hours which the utility specifies in its tariff as being times when capacity is particularly valuable. For instance, solar output may nearly reach full nameplate capacity during the noon hour, but the QF will not receive any capacity payments during this time period. Instead, the QF only receives capacity payments later in the afternoon, during the handful of "critical peak" hours which are specified in the tariff as being the ones when capacity is most needed and most valuable to the utility.

Contrary to Mr. Lynch's focus on solar nameplate capacity, this has no direct relevance to the dependability of solar capacity, the amount paid for this capacity by ratepayers, or the amount received by solar QFs for their generating capacity. The relevant data is the amount of energy provided by the QF during the On Peak hours specified in the utility's tariff. Thus, if a QF provides 4 MWh of firm, dependable electricity during the 4 hours when the utility says it is most likely to need capacity (the peak hours used for capacity pricing), it really doesn't matter to the QF or to the utility's customers if the QF had to invest in 2 MW of nameplate capacity in order to achieve this level of net output during the peak hours.

Q. CAN SOLAR NAMEPLATE CAPACITY BE DIRECTLY COMPARED TO THE NAMEPLATE CAPACITY OF OTHER GENERATING SOURCES?

A. No. There are several complicating factors which prevent meaningful conclusions from being drawn from a simple, direct comparison of nameplate capacities. Solar output varies with the sun's movement, which is highly predictable, and with cloud cover which is less easily predicted. Even the impact of cloud cover can be predicted (and will be better understood once more real time weather data is analyzed and correlated with real time metering data). In general, however, we know that solar facilities provide less capacity during the winter, because the sun is lower in the sky, and because cloud cover tends to be heavier and more frequent during the winter.

The following graph illustrates this pattern, using a data set in which the maximum hourly output of 1,000 MWh only occurred during a few hours of the year.



The orange bars show the average hourly output during June through September, and the blue bars show the analogous average hourly output during October through May. As this graph illustrates, the electrical output follows a smooth and predictable pattern once the data is averaged across multiple days. However, it is also tends to be significantly less than its nominal nameplate capacity. The extent of the discrepancy varies depending on the technology (tracking versus fixed) as well as the time of day and day of the year.

Q. DO YOU HAVE ANYTHING TO ADD, BEFORE MOVING TO THE NEXT ISSUE?

A. Yes. A more diversified energy mix has long been sought by state and federal policy makers throughout the United States. Although increases in solar production are helping to achieve this goal in South Carolina, the benefits of this increased production can easily be misjudged or overlooked. If the unique characteristics of solar production are not adequately understood and reflected in the utility's operations, some of the potential benefits to society will be lost – for instance, transmission and distribution costs that could be avoided will not be avoided if the utility fails to anticipate and react to the changes to local conditions which occur as distributed generation is introduced into the grid, or if it fails to send appropriate price signals to QFs that give them an incentive to build their facilities in locations where the potential transmission and distribution cost savings will be the highest.

Long Run versus Short Run Costs

Q. WHAT IS THE SECOND ISSUE?

A. I will respond to Mr. Lynch's claim that the proposed "rates in PR-2 reflect the Company's long-term avoided costs"[5] and respond to his challenge for me to explain how my estimates of the cost to construct a new nuclear or gas-fired generating plant relate to the long-run costs that are avoided when QF power is purchased.[6] I will also show that

5 Rebuttal Testimony of Joe Lynch, Page 23.

6 In his rebuttal testimony at page 23, Mr. Lynch states "Dr. Johnson leaves out the most important aspect of the method—how it is relevant. Specifically, he does not explain how the cost to construct these proxy plants relate to the costs SCE&G would avoid through a QF purchase, i.e., the avoided cost rates that leave ratepayers indifferent." I am providing a much more detailed and complete explanation of my reasoning here, but I would note that my direct testimony actually did include a brief explanation of one of the reasons why my proxy unit cost estimates are relevant: "all three of these methods are intended to measure the same thing (long run incremental costs), so all three methods can (and should) yield approximately the same total cost per kWh..." My proxy unit cost estimates provide an independently developed benchmark the Commission can use to evaluate the Company's proposed QF rates.

the Company's proposed QF rates are below the actual level of long-run incremental or avoided costs, and demonstrate they come closer to the (much lower) level of short-run marginal cost.

As I will explain in detail, the underlying goals of PURPA are better achieved when long-run avoided costs are used in setting QF rates, rather than using a short-run measure of costs. In fact, there is widespread agreement that PURPA is most appropriately implemented using long-run incremental costs – disagreements are typically focused on how well the QF rates come to meeting this standard, rather than whether this is the standard that should be used. Even in this proceeding, Mr. Lynch seems to acknowledge the validity of using "long-run avoided costs"[7] as the appropriate standard for judging the proposed QF rates. Succinctly stated, ratepayer indifference should be evaluated on a long-term basis, rather than limiting the evaluation to a strictly short-term basis, where many capital-related costs are zeroed out, because they are treated as fixed or sunk.

Q. WHY SHOULD RATEPAYER INDIFFERENCE BE EVALUATED USING LONG-RUN COSTS?

A. PURPA encourages the expanded use of targeted technologies and energy sources which have been neglected by the electric utility industry, and it encourages small independent

7 Rebuttal Testimony of Joe Lynch, Page 23.

power producers to compete with the incumbent utilities using these targeted technologies and energy sources, thereby creating pressure for the incumbent firms to lower their costs and become more efficient. These beneficial aspects of PURPA can best be accomplished, while minimizing any potential for adverse repercussions, by focusing on long-run avoided costs, rather than short-run costs.

In general, the long term best interests of ratepayers are of greater importance than immediate short-term impacts, and those interests are better protected and advanced when the primary focus is on long-run costs, rather than short-run costs. For example, the benefits to the public when QFs invest in solar facilities should not be judged on the basis of how the utility responds to this new source of energy over the first few years. Rather, those benefits should be judged over the entire 30+ year economic life cycle of these investments, taking into account the full range of adjustments and optimization strategies which can be implemented over the long-run.

One of the many reasons why a short term view is not desirable is because of the complications that arise when a new and relatively unfamiliar technology is adopted. When an industry is undergoing technological change, as PURPA is intended to encourage, the utility is unlikely to immediately recognize some of the cost saving opportunities that will be made possible by the new technology. Even if it sees the potential right away, it may take time to develop and implement a strategy to take full advantage of those opportunities, and thus many of the potential cost savings may not be included when looking at avoided costs from a short term perspective.

Ratepayers are better served by considering the full range of cost savings which can ultimately be achieved by QF investment over the long term. Admittedly, some portion of these savings may not be fully achieved during the first few years, particularly when focusing on the early generations of QF investments. However, those cost savings are real and they will be fully achieved in the later years of those initial investments – and during the entire life cycle of subsequent rounds of QF investment. If those longer term cost savings are ignored, the QF rates will be set too low, too little QF investment will occur, and some of the potential long term cost savings and efficiencies will never be achieved, to the detriment of ratepayers and society.

The same reasoning applies to the way capital lumpiness is handled. It is not in the long term best interests of ratepayers to discourage QF investment by setting extremely low QF rates, which include little or no compensation for capital-related costs, as can occur when capital-related costs are assumed to be fixed and unavoidable.

Accordingly, rather than only focusing on costs that can readily be avoided during the immediate short term, the concept of ratepayer "indifference" and the calculation of avoided costs should take a longer term view – preferably, considering the full incremental cost of building and operating generating facilities over their entire economic life cycle. This is the type of cost data I presented in my direct testimony, and I think it is the most appropriate standard to use in evaluating the impact of QF investment on ratepayers. It also helps achieve a higher degree of fairness and avoids discriminating against QFs. Using a long-run measure of avoided costs ensures that QFs receive the same amount for their power as the utilities receive for the power they produce using their own generating plants – no more and no less. This also helps ensure that ratepayers are not required to subsidize QF investment, since they are paid a similar amount to what the incumbent utility receives for the power it generates.

Q. PLEASE EXPLAIN THE DISTINCTION BETWEEN THE LONG-RUN AND THE SHORT-RUN.

A. The "run" is a technical term from economic theory, which is inextricably tied to the concept of a "planning horizon." The "short-run" is essentially just a time period in which the firm minimizes its costs by focusing on those options, like hiring or firing employees or adding overtime, which can be implemented quickly, without making new investments. The critically important distinction is that, in the short-run, the firm's existing capital investment is considered to be a fixed or sunk cost. Larger, more fundamental changes, like investing in more plant and equipment, or replacing some of its existing equipment with a different type of equipment (or more labor) are not options that are considered in the short-run.

In contrast, the long-run planning horizon considers changes in the total cost function as the size, design and capacity of the capital investment is varied and optimized, along with corresponding variations in operating costs. This optimization analysis is performed in a context where the firm's options are not closely tied to, or significantly constrained by, the limitations and characteristics of its existing capital investments and technology choices.

Q. ARE THE LONG-RUN AND SHORT-RUN RIGID CATEGORIES OR CAN THE DISTINCTION BE FINE-TUNED TO FIT SPECIFIC CIRCUMSTANCES?

A. The distinction between treating capital-related costs as variable and treating them as fixed or sunk is fundamental. In application, however, the theory can be quite flexible. For instance, analysts may use slightly different assumptions concerning the manner and degree to which particular aspects of the firm's operations are capable of being varied in the context of the particular planning horizon they believe is most relevant to the issue they are studying.

To reflect this flexibility, and avoid confusion, some observers will draw a distinction between the "extreme long-run" and the "long-run" or refer to a particular analysis as reflecting the "medium run." There is nothing illegitimate or inappropriate about studying a planning horizon in which some of the firm's capital investment can be varied, while some other aspects of its existing system are treated as fixed. Assumptions can be carefully tailored to fit the key questions that are being studied without deviating from the underlying economic theory.

For example, the analyst can simplify some of the calculations, or make the analysis more realistic, by assuming non-critical aspects of the firm's existing capital investment remain unchanged, or that some capital-related constraints impinge on the firm's options, provided those constraints do not lie at the heart of the issue being studied. The analyst can assume some flexibility exists to enable the firm to change its capital costs in key areas that are particularly relevant to the question being studied, while assuming some other aspects of the firm's capital investments or operations remain fixed, for the sake of simplicity.

However, when preparing a study that falls somewhere along this continuum from the classic short-run to the classic long-run, consistency is extremely important. Is the planning horizon a logical one? Is it clearly disclosed? Are internally consistent assumptions being made with respect to the degree to which various items of investment can be varied within this assumed planning horizon? Are potential reductions in output or demand being analyzed in a consistent manner with potential increases in output or demand?

Similarly, if simplifying assumptions are adopted that deviate from a classic definition of long-run costs, this is more likely to be appropriate when the simplifying assumptions are adopted with respect to aspects of the firm's operations which are not directly related to the issue being studied. Otherwise, the calculations may be greatly affected by the simplification, and the results may be closer to a short-run analysis than a long-run one. In the DRR method, for example, one cannot simply assume that capital-related costs will "not change from one plan to the next" or simply assume that capital-related costs will "cancel out" (be zeroed out) if the difference in revenue requirements is supposed to be consistent with a long-run cost analysis.[8] Variations in capital-related or capacity-related costs lie at the very heart of the issues being investigated, so they should not be simplified away.

Disclosure is also important. Is an adequate degree of planning flexibility being assumed with respect to the key issues being studied? If the assumed flexibility is rather limited, it should labeled as a "short-run" cost study – or at least, if the study does not reflect a classical "long-run" view of costs, some other label should be chosen, to avoid being misleading – perhaps the analysis can better be described as a "medium run" cost study.

8 Rebuttal Testimony of Joe Lynch, Page 24.

Q. CAN YOU PROVIDE AN EXAMPLE WHICH WILL HELP THE COMMISSION CLEARLY UNDERSTAND THE KEY DIFFERENCES BETWEEN THE LONG-RUN AND THE SHORT-RUN?

A. Yes. Before giving this example, I would note that strictly speaking, in economic theory, the "run" does not refer to a specific period of time. Rather, the "run" refers to the degree to which costs (particularly capital investments) are assumed to be variable, rather than fixed or sunk. Nevertheless, a useful way of thinking about this issue (and evaluating the degree of internal consistency) is to think about the degree to which particular items of capital investment would vary (or are assumed to vary) within a given, consistent, time period.

A classic example economists use to explain the concept of the "run" and show how it relates to time are the costs that are incurred by a fisherman. At one end of the continuum is the "extreme short-run" which exists in the narrow time frame that exists after the fisherman has already caught a load of fish and brings them to the fish market for sale. He cannot "uncatch" the fish, nor can he reduce his costs by selling some of the fish and throwing away the rest – so in this extreme case of the short-run, none of his costs are variable, and therefore his marginal cost is zero (his average costs remain well above zero).

As economists explain the classic short-run, this is a planning horizon where the fisherman has many options, but his capital costs are fixed. It is easy to envision some of these options if you visualize what the fisherman can do over the course of a week or two. For example, the cost of fuel and labor can be varied, as the fisherman decides how much time to spend on the water each day, or how many days per week he will go fishing. By spending more time on the water, the fisherman can catch more fish, but he will also burn more fuel. Looking at the same option from the other direction, he can limit the amount of fuel he is willing to use each day or week, but this will typically result in fewer fish being caught.

If he chooses to use more fuel and spend more time on the water, the marginal cost per fish will eventually begin to increase, once he reaches a point of diminishing returns, because he will be forced to spend more and more time on the water, searching farther and farther afield from the prime locations where he knows he can find a lot of fish. This extra time on the water will help him bring back a larger catch, but he will be incurring much higher variable costs, because of the extra fuel he burns. At some point if this strategy is pursued far enough, the boat might even become overloaded, and the captain will be forced to slow down when returning to shore, in order to avoid capsizing the boat. All of these factors tend to drive up the marginal cost of each pound of fish brought to shore once he goes beyond the point of diminishing returns.

Similarly, in the short-run the fisherman can hire more workers to go out on the boat with him. These workers help him haul in his nets more quickly, enabling him to increase his catch for a given expenditure on fuel. Of course, this might also increase the short-run marginal cost, since the extra workers are paid for the entire time they are on the water – not just when they are actually needed to help with bringing up the nets.

The long-run corresponds to a planning horizon where capital-related costs become relevant, and the fisherman has additional, capital-related options. While the long-run is not tied to any specific period of time, in the fishing context it can be thought of as a time period that is long enough to give the fisherman an opportunity to investigate and evaluate many more alternatives, including ones that would require him to change his capital investment.

The most obvious example is that he can sell or lease his existing boat to someone else, and replace it with a faster, more powerful boat, which would enable him to reach the prime fishing spots more quickly. Or, he could invest in a larger boat, which allows him to haul more fish back to shore (at least on days when he can find enough fish to fill the larger boat).

He could also evaluate the option of installing better, more powerful gear for hauling in his nets, which might enable him to lower his labor costs. Similarly, he could invest in technology which helps him more quickly and precisely find the fish, without wasting so much time letting down his nets and hauling them back up with a disappointing catch. In the long-run, he even has the option of investing less – or investing a similar amount, but using a different technology. For instance, he can choose a smaller, cheaper boat that costs less to own and operate, but doesn't hold as many fish. In the long-run, this might actually lower his total cost per pound of fish brought back to shore, if it is better optimized to the size of the catch he can quickly and easily find on a typical day. With the optimal size boat he can focus exclusively on the prime fishing locations, without wasting time going to other, less reliable, or less plentiful locations in an effort to fill the larger boat he currently owns.

While the difference between the short-run and the long-run are related to time, the really crucial difference is in the variability of capital costs. In the long-run the investment in his boat and its associated equipment is treated as something that can be varied, while in the short-run, he is stuck with what he already owns. The key distinction is that in the short-run, the firm is limited to those choices which make sense given the capacity, technology, configuration and other limitations of its existing capital stock.

Q. CAN YOU BRIEFLY DISCUSS HOW THE DISTINCTION BETWEEN THE SHORT-RUN AND LONG-RUN APPLIES TO ELECTRIC UTILITIES AND SETTING QF RATES?

A. Like with the fisherman who has an existing boat, short-run costs are analyzed within the context and constraints of the utility's existing system. In the long-run, the utility is assumed to have more options, including the flexibility to replace its existing capital investments, or to select a different mix of available technologies, which affects hourly fuel usage and other aspects of the avoided costs analysis.

This is a fundamental distinction, because in the long-run all costs are treated as variable – even items like generating units and transmission lines that take many years to design, obtain permission to construct and build – and the resulting investment (once constructed) will then remain in place for 30, 50 or even 70 years.

This is also a very important distinction, because in a short-run analysis capital costs are treated as fixed, and thus they tend to be zeroed out when calculating incremental or marginal cost. In turn, this has serious implications for how high or low QF rates will be set, since QF rates are based upon incremental or marginal costs, rather than average costs.

In the electric utility industry, short-run incremental or marginal costs are almost invariably less than long-run incremental or marginal costs, due to "lumpiness" of capital additions among other factors. Incremental costs are very sensitive to these issues, so the extent to which capital-related costs are being analyzed on a short-run or long-run basis can have a major impact on the numerical results – and those results may or may not be correctly labeled, since the distinction between short-run and long-run costs can sometimes be confusing.

Ratepayers are required to bear the full long-run cost of investments that are put into the rate base. If QF rates are almost entirely based on variable operating costs, while capital related costs are largely or entirely zeroed out (e.g. because they are treated as fixed or sunk), a severe mismatch will occur when comparing the amounts paid by ratepayers for power provided by the utility (which includes capital costs) and power provided by a QF (which may largely or entirely exclude capital-related costs). If a significant mismatch is allowed, ratepayer indifference will not be achieved. Stated another way, developing QF rates using short-run incremental or avoided costs will discriminate against QFs and discourage QF investment. Instead, long-run avoided costs should be used.

Q. IS YOUR OPINION THAT LONG-RUN COSTS ARE MORE APPROPRIATE FOR SETTING QF RATES CONTROVERSIAL?

A. No. To my knowledge there has never been much controversy about whether long-run or short-run avoided costs are more appropriate to use in setting QF rates. In most cases, the appropriateness of using long-run, rather than short-run, costs is so non-controversial, it is simply taken for granted.

For example, when discussing the strengths and weaknesses of the proxy unit method, the peaker method (also known as the "component approach"), and the DRR method, a report published by the Edison Electric Institute in 2006 simply assumed the appropriate standard would be how well each method comports with the "theoretical ideal" of long-term marginal cost.[9] Similarly, in this discussion of the pros and cons of each method, the report takes for granted that each method will be used to provide "long-run estimates of avoided cost."[10]

> Any long-term avoided cost forecast made in the mid-1980s, regardless of its analytical rigor or conceptual elegance, almost certainly would have overstated a utility's avoided costs in the 1990-1995 period because natural gas and oil prices during that era turned out to be far lower than projected in the mid-1980s vintage forecasts. In fact, the proxy unit method, if the proxy unit were assumed to be a coal-fired plant, would have been less sensitive to erroneous fuel price projections than the component method or the differential revenue requirement method, which base their avoided cost calculations in large part on projections of the utility's marginal energy cost. But all long-run estimates of avoided cost will be prone to forecast error regardless of the method used. Such error is inevitable; the only question is the significance and direction of the error over time.[11]

9 Edison Electric Institute, PURPA: Making the Sequel Better than the Original, December 2006, Page 12.

10 Ibid.

11 Ibid.

Q. IS THE USE OF LONG-RUN AVOIDED COSTS CONSISTENT WITH PURPA?

A. Yes. The term “long-run” is not used in the text of PURPA, nor is the term “avoided cost” used in the statute, but both terms are fully consistent with the statutory language referencing the “incremental cost of alternative electric energy,” which is defined in PURPA as: "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[12] More specifically, FERC defines avoided costs as:

> [T]he incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[13]

In the short run, capital-related (and thus, capacity-related) costs tend to be fixed or sunk, and therefore they have little or no impact on incremental or marginal costs (just as the cost of owning the boat has no impact on the short run marginal cost per pound of fish).[14] In contrast, capital-related costs are variable in the long-run; they represent a major portion of the cost of generating electricity.

Stated a little differently, in the long run, the cost of building and owning generating plants is an inextricable, vitally important element of the incremental cost of generating

12 16 U.S.C. § 824a-3(d)

13 18 CFR § 292.101(b)(6).

14 Capacity-related costs are a subset of capital-related costs. Some capital-related costs are energy-related.

electricity. These are costs which the utility will inevitably incur, and ratepayers will reimburse, however the utility goes about generating electricity for itself. Conversely, these capital-related or capacity-related costs can be avoided if the utility purchases power from a QF rather than generating the power itself. For this reason, it is entirely appropriate to estimate incremental or avoided costs from a long-run perspective, so that capital-related costs will not be underestimated or zeroed out.

Q. HOW DOES THE COST OF BUILDING NEW GENERATING PLANTS RELATE TO QF RATES THAT LEAVE RATEPAYERS INDIFFERENT?

A. Capital-related costs need to be considered in order to leave ratepayers indifferent. If capital-related costs are not recovered through the QF rates, ratepayers will not be indifferent over the long haul – they would much prefer getting as much power as possible from QFs, since this would enable them to avoid paying capital-related costs, which they would be required to pay if they use electricity that is generated by the utility.[15]

While I am not an attorney, as an economist I find it hard to see how the statutory requirement that QFs must be paid an amount that is equivalent to "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small

15 Excluding capital-related costs from the QF rates may seem to create a "free lunch" but QF investment will be discouraged, and ratepayers will lose the long-term benefit of low cost solar power. Ratepayers will also lose the benefit of competitive pressure for increased efficiency and cost-cutting.

power producer, such utility would generate or purchase from another source"[16] can be met, if capital related costs are largely or entirely zeroed out by using a short-run measure of incremental costs, rather than long-run costs. At least to me, it seems abundantly clear that when the utility generates electric energy itself, the cost of that energy includes capital-related costs. This is certainly how costs are viewed when retail rates are set. As well, it is clear that the goals of PURPA can be more effectively achieved if QF rates are based on long-run avoided costs rather than short-run costs.

This interpretation also seems more consistent with the provision in PURPA which states that QF rates must not "discriminate against qualifying cogenerators or qualifying small power producers."[17] Under rate base regulation, the incumbent utilities are allowed to recover the cost of new generating plants as they are completed and put into commercial operation (allowance for funds used during construction is accrued prior to that time), even though some of the capacity is being added prior to the time it is required (due to lumpiness). To avoid discrimination, the QF rates should give QFs similar treatment – small power producers should be paid for the energy and capacity they provide to the utility as soon as a new QF starts sending energy to the grid.

16 16 U.S.C. § 824a-3(d)

17 16 U.S.C. § 824a-3(a).

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY "LUMPINESS" AND HOW THIS RELATES TO THE ISSUES IN THIS PROCEEDING?

A. Because of economies of scale, utilities often find it more cost effective to construct very large generating plants. These plants are so large, they only need to be added at multi-year intervals, rather than being added in smaller increments throughout the year.[18] For example, assume the utility decides the optimum size plant is 600 MW or larger. If the utility needs to add capacity at the rate of 100 MW per year, it will not add a 100 MW plant every year. Instead, it will add a 600+ MW plant in a single year, then wait 5 or 6 years before adding another 600+ MW plant, then wait another 5 or 6 years before adding another 600+ MW plant. Under these circumstances, economic theory tells us that long run capacity costs are being incurred every year; they are not zero in some years and present in others.

This results in a stair-step pattern, in which there are zero additions to generating capacity (and zero additions to rate base) in most years, and large increases in capacity and rate base in other years. This stair step pattern (which economists call "lumpiness") shows zero physical need for new capacity in most years. In reality, however, the utility is growing even during the years where capital additions are not occurring, and its older plants are slowly becoming costlier to maintain and operate, as they gradually near retirement. Under these circumstances, the long run cost of capacity is actually very

18 Meters are an example of investments that do not exhibit lumpiness. Meters are added every month, as new buildings are connected to the grid.

similar in years when "zero" capacity is needed or planned as it is during the years when a new block of capacity is scheduled to enter commercial operation.

Stated another way, we know from economic theory the absence of a pressing need for new capacity during some years (the reserve margin is adequate and zero MW is scheduled to be added) does not mean capacity has an economic value of zero during those years. Nor does it mean that the long run incremental or avoided cost of capacity is zero during those years.

Conclusion

Q. IF THE COMMISSION AGREES WITH THIS REASONING, WHAT COURSE OF ACTION DO YOU RECOMMEND?

A. I recommend the Commission reject the SCE&G's proposed QF rates, and require the Company to modify its QF tariff to include rates which come closer to those the Commission has approved for DEC and DEP.

The following tables, which are similar to ones I included in my direct testimony, show the proposed energy rates and the proposed capacity rates are both more than a penny lower (per kWh) than the analogous QF rates in the tariffs the Commission approved for DEC and DEP.

	Difference in QF Rates: Duke Progress Current versus SCE&G Proposed			
		Energy	Capacity	Total
1	Duke Progress	4.352 cents	1.242 cents	5.594 cents
2	SCE&G – Proposed	3.156 cents	0.149 cents	3.306 cents
3	Difference (2-1)	-1.196 cents	-1.093 cents	-2.288 cents
4	Percentage Difference	-27.5 %	-88.0 %	-40.9 %

	Difference in QF Rates: Duke Carolinas Current versus SCE&G Proposed			
		Energy	Capacity	Total
5	Duke Carolinas	4.433 cents	1.321 cents	5.754 cents
6	SCE&G – Proposed	3.156 cents	0.149 cents	3.306 cents
7	Difference (6-5)	-1.277 cents	-1.171 cents	-2.448 cents
8	Percentage Difference	-28.8 %	-88.6 %	-42.5 %

I recommend the Commission require SCE&G to increase their standard offer QF rates by at least 1.5 cents per kWh (in total, including the energy and capacity portions), in order to bring them closer to the level paid by Duke, and my benchmark estimates of the Company's long run avoided costs.

This is consistent with my direct testimony, where I recommended the Commission should adopt QF rates in this proceeding which are closer to those it has approved for Duke Carolinas and Duke Progress, as well as the long run avoided cost estimates provided in my direct testimony.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE

THE PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2017-2-E

IN RE: Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company	))))))	**CERTIFICATE OF SERVICE**

I, Carrie A. Schurg, an employee of Austin & Rogers, P.A., certify that I have served copies of the Surrebuttal Testimony of Dr. Ben Johnson on behalf of Intervenor, South Carolina Solar Business Alliance, LLC, Cover Sheet and this Certificate of Service, via electronic mail on April 3, 2017.

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April 3, 2017
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